Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the Indeck Wharton Energy Center

Permit Number: PSD-TX-1374-GHG

April 2014

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR § 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR § 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On June 20, 2013, Indeck Wharton Energy Center (Indeck) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions. In connection with the same proposed new major stationary source, Indeck submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on June 17, 2013.

Indeck proposes to construct a 650 MW peaking power project located near Danevang, Wharton County, Texas. With this proposed project, Indeck plans to construct three identical natural gas-fired simple cycle turbines, utilizing either the GE Model 7FA.05 or Siemens SGT6-5000F(5), and associated equipment, an emergency diesel generator, a gas pipeline heater, a firewater pump engine, and fourteen circuit breakers. For the purposes of this proposed permitting action, GHG emissions are permitted from the three turbines, the emergency diesel generator, the gas pipeline heater, the firewater pump engine, fugitive emissions from circuit breakers and piping components, and maintenance, startup and shut down emissions. The remaining units are not considered to be potential GHG emission sources. After reviewing the application and supplemental information provided by Indeck, EPA Region 6 prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Indeck Wharton Energy Center.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Indeck's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations.

EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by Indeck, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

Indeck Wharton, LLC
Indeck Wharton Energy Center
600 North Buffalo Grove Road, Suite 300
Buffalo Grove, IL 60089

Facility Physical Address:
State Route 71, 0.5 miles south of Danevang
Wharton County, Texas

Contact:
Mr. Jim Schneider
Senior Environmental Engineer
600 North Buffalo Grove Road, Suite 300
Buffalo Grove, IL 60089
(847) 520-3212

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). Texas retains PSD permitting authority for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Jennifer Huser
Air Permitting Section (6PD-R)
1445 Ross Avenue
Dallas, TX 75202
(214) 665-7347

IV. Facility Location

The Indeck Wharton Energy Center is located in Wharton County, Texas. Wharton County is currently designated attainment for all criteria pollutants. The Indeck Wharton Energy Center is to be located on a rural, sparsely occupied 154 acre plot of land on State Route 71, 0.5 miles south of the city of Danevang in Wharton County, Texas. The proposed facility is 535 miles away from the nearest Class I area (Big Bend National Park).

The geographic coordinates for this facility are planned to be as follows:

Latitude: 29° 03’ 08”
Longitude: 96° 12’ 54”

The following figures illustrate Indeck Wharton facility location and the proposed site layout for this draft permit.

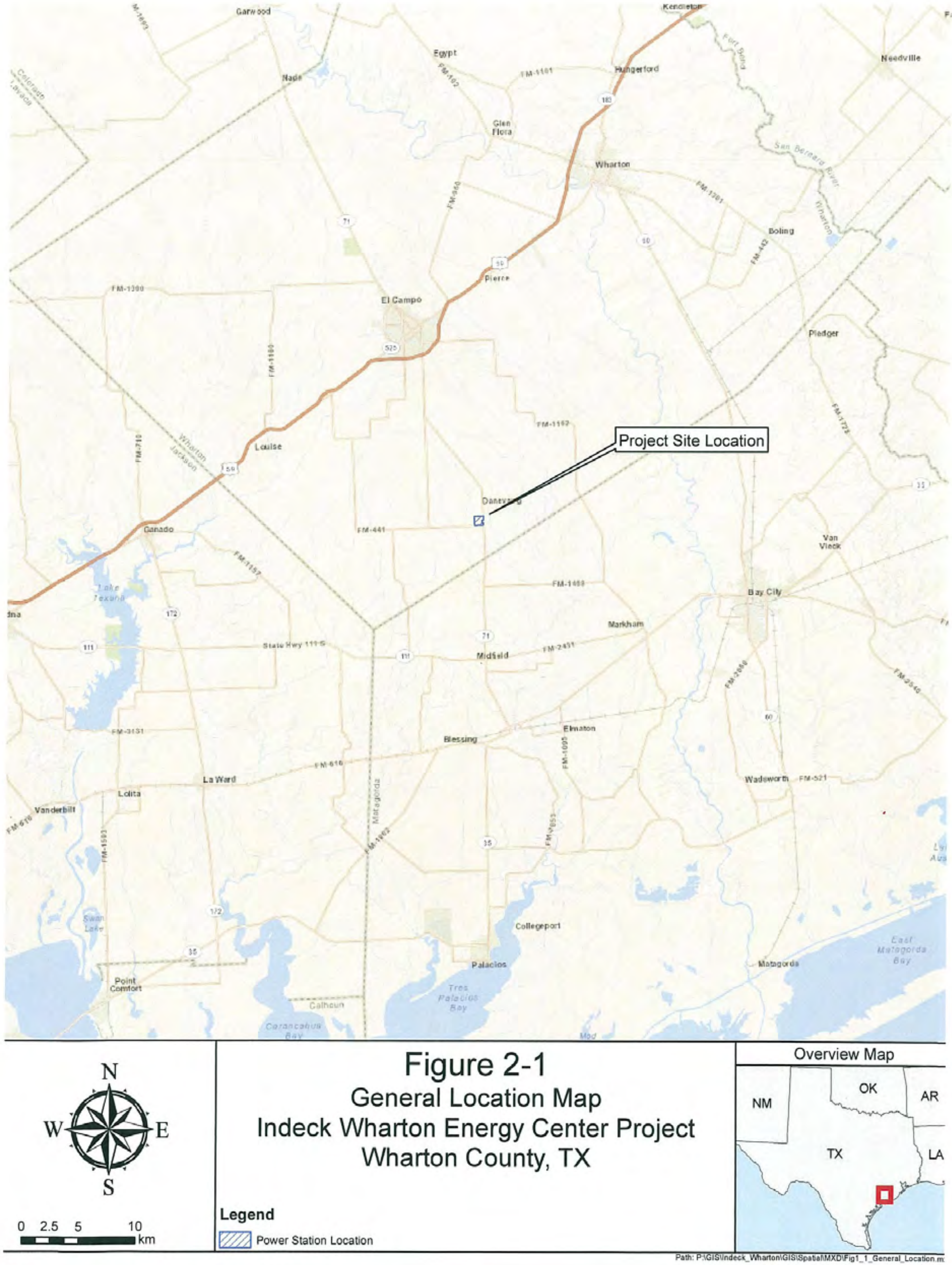

Figure 2-1
General Location Map
Indeck Wharton Energy Center Project
Wharton County, TX

V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes Indeck's application is subject to PSD review for the pollutant GHGs because the facility will be a new major stationary source for nitrogen oxides (NOx) and carbon monoxide (CO) and also will emit or has a potential to emit 75,000 tons per year (tpy) carbon dioxide equivalent (CO_2e) or more, as described at 40 CFR § 52.21(b)(49)(iv)(*a*). Alternatively, EPA concludes Indeck's application is subject to PSD review for the pollutant GHGs because the facility will constitute a new stationary source that will emit or have the potential to emit greater than 100,000 tpy CO_2e, as described at 40 CFR § 52.21(b)(49)(v)(*a*).

EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. Indeck represents that TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, will determine that Indeck is also subject to PSD review for increases of NOx and CO. Accordingly, under the circumstances of this project, TCEQ will issue the non-GHG portion of the permit and EPA will issue the GHG portion.[1]

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ. Thus, TCEQ's PSD permit that will address regulated NSR pollutants other than GHGs should address the additional impacts analysis and Class I area requirements for those other pollutants as appropriate.

VI. Project Description

Indeck proposes to construct a peaking power plant, the Indeck Wharton Energy Center, generally located south of Danevang, Texas. To meet the anticipated demand for peak power, Indeck proposes to construct three identical natural gas-fired F-class simple cycle combustion turbines with associated support equipment. Indeck proposes that the three new combustion turbine generators (CTGs) will be either General Electric (GE) 7FA.05 or Siemens SGT6-5000F(5). The GE 7FA.05 has a base-load electric power output of approximately 213 megawatts (MW, net nominal), and the Siemens SGT6-5000F(5) has a base-load electric power output of approximately 225 MW (net nominal). This project also proposes to install one emergency diesel generator, one diesel fire water pump, one natural gas pipeline heater, and other auxiliary equipment. GHG emissions will result from the following emission units:

- Three Simple cycle CTGs (EPNs: GT1, GT2, and GT3);
- One Emergency Diesel Generator (EPN: EDG);
- One Fire Water Pump Engine (EPN: FP);
- One Natural Gas Pipeline Heater (EPN: NG);

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

- Fugitive Emissions from SF_6 Circuit Breakers (EPN: SF6); and,
- Fugitive Emissions from Piping Components (EPN: FUG)

Process Description and Process Flow

The following presents a process flow diagram for the three simple cycle combustion turbines proposed for the Indeck Wharton Energy Center. The power block will have the potential to generate a nominal 650 MW of electricity.

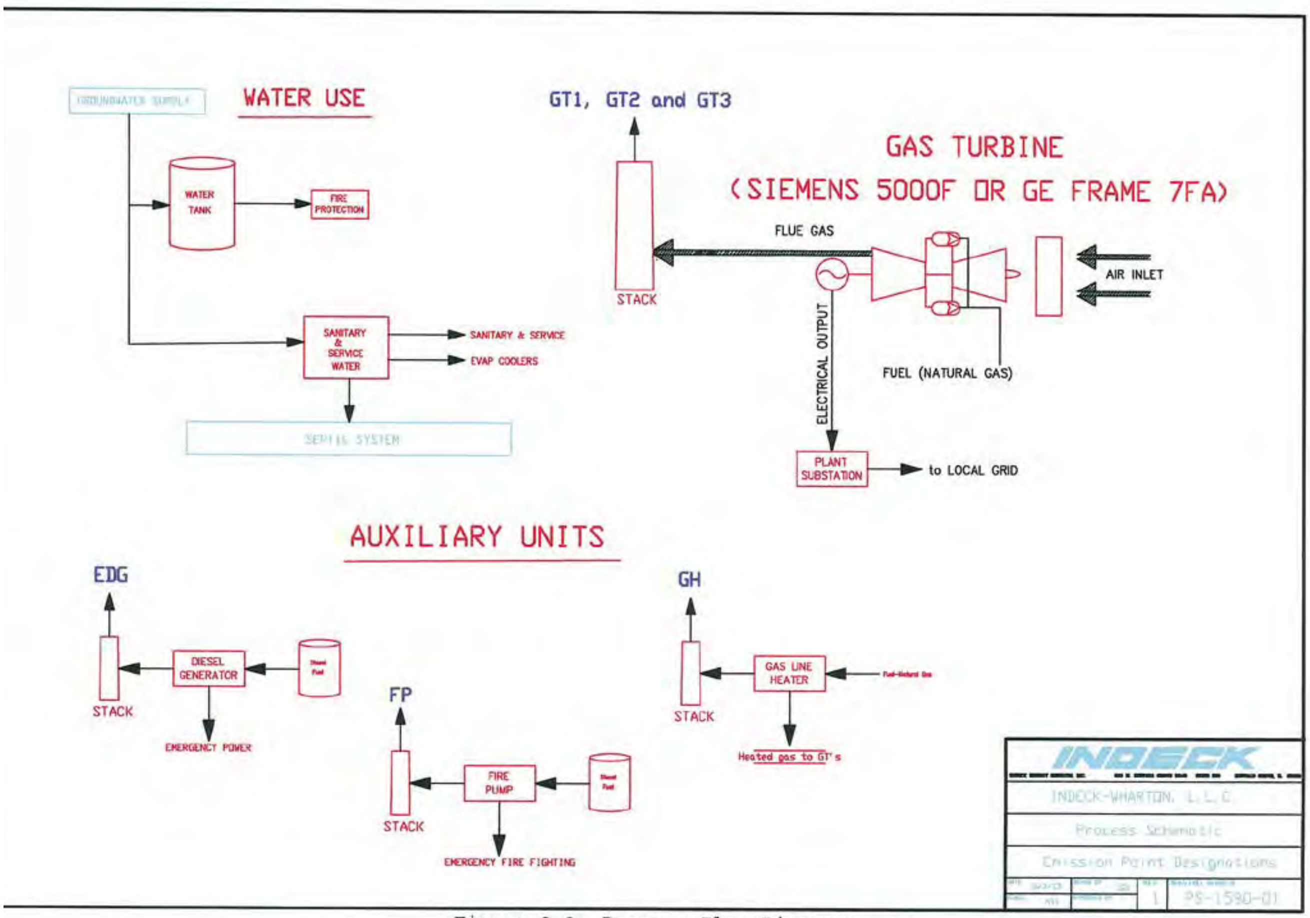

Figure 2-3: Process Flow Diagram

Combustion Turbine Generators

Indeck is a privately held developer, owner, and operator of power generation facilities. In addition to the proposed peaking unit in Wharton County, Indeck owns several other domestic generation projects, including cogeneration and independent power production facilities.

As a member of the Electric Reliability Council of Texas (ERCOT), Indeck is responsible for meeting the requirements and standards for reliable and adequate bulk power transmission by the National Electric Reliability Corporation (NERC) and ERCOT. NERC is the entity certified by the Federal Energy Regulatory Commission (FERC) to establish and enforce reliability standards for the bulk power system. In an agreement between NERC and ERCOT, the ERCOT provides the coordination and promotion of electric system reliability for a region that covers a majority of Texas. In 1999, the Texas Legislature restructured the Texas electric market by unbundling the investor-owned utilities and created a retail customer choice for service areas. ERCOT has the following responsibilities: system reliability, open access to transmission, retail switching process for customer choice, and wholesale market settlement for electricity production and delivery. As a member of ERCOT, Indeck has agreed to provide reliable operation of a portion of the bulk electric system for the Texas service area.

Due to projected energy supply shortages in the ERCOT grid, particularly in the Houston area, Indeck is proposing to construct three identical natural gas-fired simple cycle CTGs to meet demand for peak power in the ERCOT service area. Each CTG will burn pipeline natural gas to rotate an electrical generator to produce electricity. The main components of a CTG consist of a compressor, combustor, turbine, and generator. The compressor pressurizes combustion air to the combustor where the fuel is mixed with the combustion air and burned. Hot exhaust gases then enter the turbine where the gases expand across the turbine blades, driving a shaft to power an electric generator. To increase the density of the inlet air to the turbine compressor and allow for a higher mass flow of combustion air, Indeck will utilize evaporative cooling on the intake air of the compressors. The inlet air will be cooled using trickling filters within the air inlet of each combustion turbine. Use of inlet air cooling increases the gas turbine output and provides a slight improvement in the efficiency of the turbines. The evaporative coolers are not a source of GHG emissions.

The BACT analysis provided by the company considers two simple cycle CTG models: GE 7FA.05 and SGT6-5000F(5). Information on other turbine models and turbine efficiency addressed in recent permit actions is also discussed as part of EPA's BACT analysis for this facility.

In 2012, renewable energy resources (other than hydroelectric) accounted for approximately five percent of the electricity generated by electric utilities.[2] The use of solar and wind power poses a variety of problems for utilities primarily due to the uncontrollability of the power source and the high degree of variability. An alternative considering renewable resources as a primary fuel was not addressed in the BACT analysis because these interruptible sources are not suited for the primary purpose of the proposed peaking project.

[2] U.S. Department of Energy, Energy Information Administration, *Frequently Asked Questions*, September 30, 2010, http://www.eia.gov/tools/faqs/faq.cfm?id=427&t=3.

Fire Water Pump Engine

The site will be equipped with one nominally rated 175-hp diesel-fired firewater pump engine (Cummins CFP7E-F10 Driver, or equivalent) to provide water in the event of a fire. The fire water pump engine will operate on low sulfur (0.0015%) fuel and will be limited to 52 hours per year of non-emergency operation for purposes of maintenance checks and readiness testing. The fire water pump will meet Tier 3 standards for off-road diesel engines under 40 CFR Part 89.

Emergency Diesel Generator

The project will include an emergency diesel generator (EDG) engine (Caterpiller C18 ATAAC diesel engine, or equivalent) with a standby generating capacity of 600 ekW. The EDG will operate on low sulfur (0.0015%) diesel fuel and will be an EPA-certified Tier 2 engine. The EDG will be limited to 100 hours of non-emergency operation for the purposes of maintenance and testing.

Natural Gas Pipeline Heater

The project will include a 3 MMBtu/hr gas pipeline heater. The heater will be fired with natural gas and will be limited to annual operations of 3,500 hours per year. This equates to the operational limit on the turbines of 2,500 hours on a rolling 12-month basis, plus 1,000 hours to include startups and shutdowns.

Electrical Equipment Insulated with Sulfur Hexafluoride (SF_6)

The circuit breakers associated with the proposed units and associated equipment will be insulated with SF_6. SF_6 is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF_6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF_6 is only used in sealed and safe systems which under normal circumstances do not leak gas. The total capacity of the circuit breakers associated with the proposed plant is currently estimated not to exceed 6,122.6 lb SF_6. The proposed circuit breakers will have a low pressure alarm and a low pressure lockout. The alarm will alert personnel of any leakage in the system and the lockout prevents any operation of the breaker due to lack of “quenching and cooling” of SF_6 gas.

Fugitive Emissions from Piping Components

Emissions from piping components (valves, flanges, pressure relief valves, and connectors) associated with this project consist primarily of methane (CH_4). Fugitive natural gas emission factors were obtained from Oil and Gas Production Operations from Addendum to TG-360, Emission Factors for Equipment Leak Fugitive Components, TCEQ, January 2008, Average Emission Factors – Petroleum Industry (Table 4). The piping associated with this project will include 103 valves, 309 flanges, 10 pressure relief valves, and 570 connectors. Indeck will also conduct maintenance purges of the natural gas pipeline to clear the lines and gas filters from debris. Indeck estimates that this activity will be conducted once every two to three years, resulting in 125 lbs of methane emissions per year.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with EPA's "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control options;
(4) Evaluate the most effective controls (taking into account the energy, environmental, and economic impacts) and document the results; and
(5) Select BACT.

VIII. Natural Gas Fired Simple Cycle Combustion Turbines BACT Analysis (EPNs: GT1, GT2, and GT3)

Step 1 – Identify all available control options

The first step in the top-down BACT process is to identify all "available" control options. In general, if a control option has been demonstrated in practice on a range of exhaust gases with similar physical and chemical characteristics and does not have a significant negative impact on process operations, product quality, or the control of other emissions, it may be considered as potentially feasible for application to another process.

Carbon Capture and Storage (CCS) – CCS is classified as an add-on pollution control technology, which involves the separation and capture of CO_2 from flue gas, pressurizing of the captured CO_2 into a pipeline for transport, and injection/storage within a geologic formation. CCS is an add-on pollution control option for "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[3]

CCS contains three major components: carbon capture, transport and storage. With respect to carbon capture, CCS systems use adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is suitable primarily to gasification plants, where solid fuel

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[3] U.S. EPA, Office of Air Quality Planning and Standards, PSD and Title V Permitting Guidance for Greenhouse Gases. March 2011. Available at: http://www.epa.gov/nsr/ghgdocs/ghgpermttingguidance.pdf.

such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine facilities and requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered control options for this proposed gas turbine facility because these technologies do not presently appear to have the potential for practical application to this type of facility. The third approach, post-combustion capture, is an available option for gas turbines.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines on at least part of the exhaust gas stream (Reddy, Scherffius, Freguia, & Roberts, 2003). As such, post-combustion capture is the sole carbon capture technology considered in this BACT analysis.

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). This process has been used successfully to capture approximately 320 to 350 tons per day of CO_2 from a 13 to 15% slipstream of the exhaust gas from a natural gas combined cycle plant owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture operation at the plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003). The CO_2 capture operation was discontinued in 2005 due to a change in operations from a baseload unit to a peaking unit, which created technical impediments to continuing to operate the system.

In applications where CO_2 has been captured from the flue gas, the captured CO_2 is typically compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 may then be transported to an appropriate location for underground injection if a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, is available or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.

Combined cycle CTGs – As stated in the "PSD and Title V Permitting Guidance for Greenhouse Gases," combined cycle CTGs should be listed as an option for proposed natural gas-fired projects. However, the guidance also recognizes that this option may be evaluated under the redefining-the-source framework and excluded from Step 1 on a case-by-case basis if it can be shown that application of this control technology would disrupt the applicant's basic or fundamental business purpose for the proposed facility.[4] The applicant's project is intended as a peaking power provider operating no more than 2,500 hours per year and is designed to provide power quickly when dispatched by the grid operator, to respond to varying needs of the electric grid, and to expeditiously shut down when no longer needed. Simple cycle turbines, such as the CTGs selected by the applicant, are well suited for peaking power supply due to their ability to rapidly respond to immediate needs for additional power generation at variable levels and quickly cease operation when these additional power needs are satisfied.

Combined cycle units generally have higher efficiencies than simple cycle units; however, while combined cycle units are well suited to operate as baseload power electric generating units, EPA has not concluded, at this time, that combined cycle units can provide the rapid response and shutdown required of a peaking power source with limited hours of operation producing power to sell in a deregulated market. The start-up sequence for a combined cycle plant includes three phases: 1) purging of the heat recovery steam generator (HRSG); 2) gas turbine speed-up, synchronization and loading; and 3) steam turbine speed-up, synchronization and loading. The third phase of this process is dependent on the amount of time that the plant has been shut down prior to being restarted, because the HRSG and steam turbine contain parts that can be damaged by thermal stress and require time to heat up and prepare for normal operation. For this reason, the complete startup time for a combined cycle plant is longer than that of a similarly sized simple cycle plant.[5] Fast-start technology is capable of enabling startup of a combined cycle combustion turbine within 30 minutes; however, this technology requires that the unit be maintained in a state allowing warm or hot startup. To keep the HRSG and the steam turbine seals and auxiliary equipment at a sufficiently high temperature to allow for quick startup of the combustion turbine, the facility would have to continuously operate an auxiliary boiler. Cold startup of a combined cycle combustion turbine with fast-start technology may take as long as 90 minutes. Use of a combined cycle configuration as a peaking unit may result in thermal mechanical fatigue due to the large numbers of startups and shutdowns.

In supplemental information provided to EPA,[6] Indeck noted that the simple cycle configuration is suitable for the intended utilization of limited, flexible, and on-demand operations, while the capital cost

[4] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, at 29-30, March 2011, http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf.
[5] U.S. Environmental Protect Agency, Region 9. Fact Sheet and Ambient Air Quality Impact Report for the Proposed Prevention of Significant Deterioration Permit, Pio Pico Energy Center.
[6] Email from Jim Schneider to Jennifer Huser, February 3, 2014.

for a combined cycle combustion turbine configuration would preclude operation as a peaking unit under the proposed permit and market conditions. Indeck stated that project economics for a combined cycle unit would rule out the limited operating hours proposed for this peaking power project and would necessitate operation as an intermediate or baseload facility.

Indeck's business purpose requires the ability to accommodate limited, flexible and on-demand operations, including the operational flexibility to startup and shutdown to respond immediately to variable electricity grid demand. Therefore, based on the defined business purpose of the proposed project and for the reasons discussed herein, the use of combined cycle units would result in a redefinition of the source for this specific project and is excluded from Step 1 of this BACT analysis.

Efficient Combustion Turbine Design – A key factor in minimizing GHG emissions is to maximize the efficiency of electricity production. Older, inefficient turbines consume more fuel to generate the same amount of electricity as newer, more efficient turbines. This is due to equipment wear and tear, improved design in newer models and the use of higher quality metallurgy. Use of modern, efficient simple cycle combustion turbine models is an available control option.

Fuel Selection – In 2008, approximately 70% of the electricity used in the United States was generated by burning fossil fuels (e.g., coal, natural gas or petroleum liquids). Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. The applicant evaluated the use of coal, distillate oil and natural gas as fuel for the CTGs.

Good Combustion, Operating, and Maintenance Practices – Good combustion, operating, and maintenance practices are a potential control option for improving the fuel efficiency of the combustion turbine. Natural gas-fired combustion turbines typically operate in a lean pre-mix mode to ensure effective staging of air/fuel ratios in the turbine, thus maximizing the fuel efficiency and minimizing incomplete combustion. Modern combustion turbines have sophisticated instrumentation and controls to automatically control the operation of the combustion turbine. The control system monitors the operation of the unit and modulates the fuel flow and turbine operation to achieve optimal high-efficiency, low emissions performance.

Inlet Air Cooling – Chilling the incoming air increases the thermal and power efficiency of the combustion turbine. An evaporative cooling system will be used to cool the incoming combustion turbine air (to approximately 60^oF) in order to increase the combustion air mass flow. Chilling the incoming air in this way increases the thermal efficiency and power gain of the combustion turbine, thus reducing GHG emissions.

There are three commercial systems for cooling the inlet air to a combustion turbine:

a. Foggers – Atomized, demineralized water is sprayed into the inlet air of the combustion turbine. The cooling effect is created by the evaporation of the water droplets. This process has been used in many installed combustion turbines and has proven to be very efficient, especially in very dry, desert-like areas. However, turbine suppliers are discouraging power plant operators from using these systems due to many reported incidents of droplet impingement damage to the air compressor section of the gas turbine. General Electric does not recommend inlet fogging for their combustion turbines due to erosion concerns for the first stage of compressor blades. Furthermore, air foggers require the installation of demineralized water treatment systems.

b. Refrigeration Units – Coils carrying a cooled aqueous solution of glycol are placed in the inlet structure of a gas turbine to cool the incoming air. These systems have become more popular in humid regions of the world where the effect of evaporative cooling is very limited.
c. Evaporative Coolers – A film of water is distributed downward through a plastic media. The inlet air of the gas turbine passes through the media and the water is evaporated, causing a drop in the air temperature similar to the foggers described above. The difference between the systems is that in the case of evaporative coolers, demineralized water is not necessary, and in many cases only filtration is required as pretreatment of the water.

Step 2 – Elimination of Technically Infeasible Alternatives

Carbon Capture and Storage: As discussed in the August 2010 Report of the Interagency Task Force on Carbon Capture and Storage (co-chaired by US EPA and US Department of Energy), while amine- or ammonia-based CO_2 capture technologies are commercially available, they have not been demonstrated nor utilized commercially for simple cycle electric generating units operating as peaking power providers with multiple starts and stops to respond to electricity demand dispatch requirements. Peaking units frequently cycle their operation, thus it is unclear how part-load operation and frequent startup and shutdown events would impact the efficiency and reliability of a CCS system. EPA is not aware of any pilot scale project that has operated in a cycling mode. Indeck's proposed project is to be operated solely in a frequent cycling mode, thus carbon capture is not applicable to Indeck's proposed peaking power project. Further, EPA is not aware of any CCS system that is commercially available at this time for a simple cycle combustion turbine peaking unit. Therefore, CCS is not technically feasible at this facility.

Since CCS is eliminated in Step 2 of the BACT analysis, EPA need not include a cost analysis in its evaluation of this option and is not addressing a cost analysis in Step 4 of the BACT analysis. However, Indeck submitted a cost analysis for CCS as part of the application, and that analysis is included in the administrative record.

Efficient Combustion Turbine Design: The applicant documented its considerations in selecting particular turbine models for this facility, while weighing operational variables such as project size, project purpose, fuel use, technical feasibility, and ambient conditions. The turbine models selected by Indeck are considered efficient, modern simple cycle turbines. Operation of these turbines has been demonstrated in practice at similar facilities, thus this is a technically feasible option.

Aside from CCS, the remaining control options identified in Step 1 have been demonstrated in practice and are thus considered technically feasible and are being proposed for Step 3 analysis.

Step 3 – Ranking of Remaining Control Technologies Based on Effectiveness

- Efficient Turbine Design,
- Fuel Selection,
- Good Combustion, Operating, and Maintenance Practices, and
- Use of Evaporative Cooling.

Selection of highly efficient simple cycle combustion turbines is considered the most effective control technology in this analysis. Fuel selection; good combustion, operating and maintenance practices; and the use of evaporative cooling are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking of those control technologies based on effectiveness is not possible. In assessing CO_2 emissions for the three potential fuel types, natural gas combustion results in lower GHG emissions (119 lbs CO_2e/mmBtu) than distillate oil (163 lbs CO_2e/mmBtu) or coal (243 lbs CO_2e/mmBtu).

Step 4 – Evaluation of Control Technologies with Consideration of Economic, Energy and Environmental Impacts

Efficient Combustion Turbine Design: The applicant assessed various turbines operating in a simple cycle configuration. Both the GE7FA.05 and the Siemens SGT6-5000F(5) meet the technical requirements of the project and are considered efficient combustion turbine designs.

Fuel Selection: As discussed in Step 3, natural gas produces the lowest GHG emissions and is the top ranked option. After considering environmental impacts associated with burning distillate oil and coal, selection of these fuel types over natural gas is not justified.[7]

EPA concludes that natural gas is the appropriate fuel for this source and no economic, energy or environmental impacts warrant elimination of this control option.

Good Combustion, Operating, and Maintenance Practices: EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Use of Evaporative Cooling: After considering the capital cost of the evaporation systems, the cost of water treatment, the cooling efficiency of the systems, and the energy consumed by the technologies, EPA is eliminating foggers and refrigeration units as BACT. Refrigeration units have a very high parasitic load and are very costly to install, and inlet foggers require demineralized water, which also requires additional energy consumption. Evaporative coolers represent the most energy efficient means

[7] From Indeck permit application, p. 5-3

of cooling inlet air to a simple cycle combustion turbine, and EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Step 5 – Selection of BACT

To date, other similar peak power facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Puget Sound Energy Fredonia Generating Station Mt. Vernon, Washington	Peak Power, Simple cycle combustion turbine, to provide an additional 181-207 MW	Energy Efficiency/ Good Design & Combustion Practices	GE 7FA.05 Option: 1,299 lb CO_2e/MWhr (net) 311,382 tpy CO_2e GE 7FA.04 Option: 1,310 lb CO_2e/MWhr (net) 274,496 tpy CO_2e SGT-5000F4 Option: 1,278 lb CO_2e/MWhr (net) 301,819 tpy CO_2e GE LMS100 Option: 1,138 lb CO_2e/MWhr (net) 327,577 tpy CO_2e	2013	PSD-11-05
EFS Shady Hills LLC EPA Region 4	Simple cycle combustion turbine, to provide an additional 436 MW	Energy Efficiency/ Good Design & Combustion Practices	GE 7FA.05: 1,377 lb CO_2e/MWhr (gross) when firing natural gas	2014	PSD-EPA-R4013

From this analysis, EPA has concluded that the GHG BACT for Indeck is the use of modern natural gas-fired, thermally efficient simple cycle combustion turbines combined with evaporative cooling and good combustion and maintenance practices to maintain optimum efficiency. The GE FA7.05 or Siemens SGT6-5000F(5) turbines are consistent with the BACT requirement and the specific goal of this project. EPA is proposing an emission limit of 1,276 lb CO_2/MWhr gross output on a 2,500 operational hour rolling basis for the GE 7FA.05 combustion turbine, or 1,337 lb CO_2/MWhr gross output for the Siemens SGT6-5000F(5) combustion turbine.

Each combustion turbine is limited to 2,500 hours of operation, plus 300 startup and shutdown events on a 12-month rolling basis. With a rolling operational hour BACT limit, the data collected over an operational hour is averaged and divided by the amount of electricity that is produced during the corresponding operational hour. The quotient is added to the 2,500 operational hour rolling basis. Until the 2,500 operational hour basis has been established, the company should utilize the performance testing data to establish a plan whereby the company may operate the emission unit in a manner that will not exceed the permitted CO_2 emissions limits.

The company is responsible for demonstrating compliance with the permitted emission limits and should evaluate its actual emissions and verify actual compliance from recorded operational data. The operating scenario provided by the applicant (2,500 hours at 100% load per year) was used to calculate the worst-case emission rates from the facility.

To account for the additional hours of operation associated with the startup and shutdowns, each turbine is limited by fuel use associated with the 2,500 hours of operation per year. Limiting the fuel use achieves the same objective as limiting the number of hours of operation of each turbine to 2,500 hours. The fuel use limit for each combustion turbine that corresponds to the 2,500 hour of operation on a 12-month rolling basis is 5,394,500 MMBtu (HHV) on a 12-month rolling basis for the GE 7FA.05 combustion turbine, or 6,024,650 MMBtu (HHV) on a 12-month rolling basis for the Siemens SGT6-5000F(5).

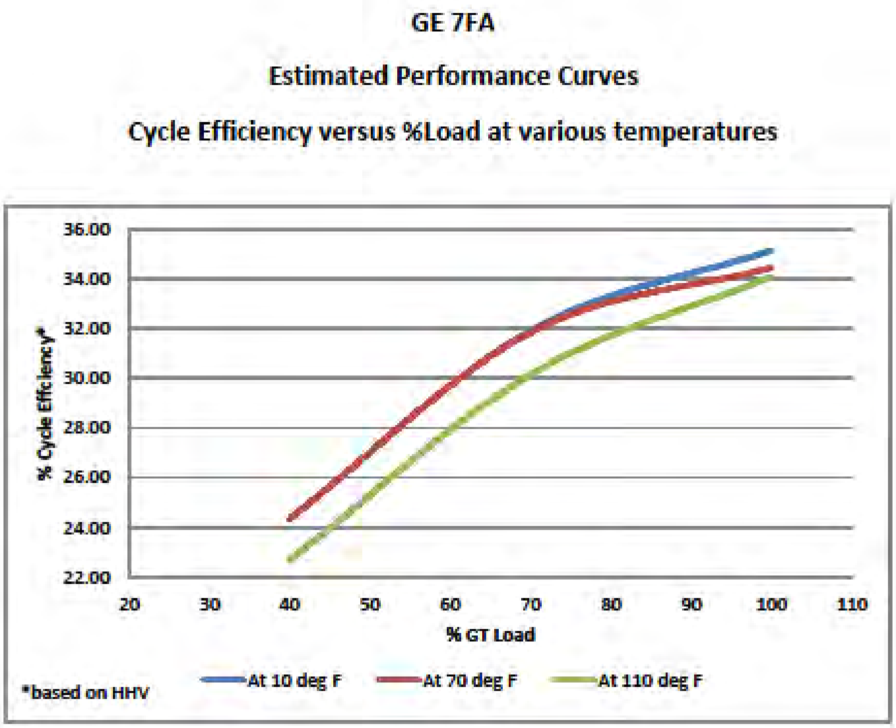
The proposed BACT limit of 1,276 lb CO_2/MWhr (gross) for the GE 7FA.05 combustion turbine or 1,337 lb CO_2/MWhr (gross) for the Siemens SGT6-5000F(5) combustion turbine is comparable to or lower than the other recently issued GHG BACT limits for peak power projects. The recently issued EFS Shady Hills LLC permit contains a GHG BACT limit of 1,377 lb CO_2e/MWhr (gross) for a GE 7FA.05 combustion turbine.

Net output generation is a measurement of the energy available minus the output consumed in any way related to the generation. The proposed Indeck GHG BACT limit, if converted to a net basis, is calculated to be 1,288 lbs CO_2/MWhr for the GE 7FA.05 or 1,350 lbs CO_2/MWhr for the Siemens SGT6-5000F(5). For the Indeck project, the difference between gross and net power output from either the GE 7FA.05 or the Siemens SGT6-5000F(5) will average less than 1% over the anticipated operating loads and ambient conditions. When comparing the net-based BACT limit for the Puget Sound Energy Fredonia Generation Station ("PSE Fredonia") and the Indeck project, PSE Fredonia has a higher (less stringent) net output BACT limit for the GE 7FA.04 and GE 7FA.05 turbines but lower (more stringent) net output based BACT limits for the Siemens SGT6-5000F and GE LMS100 turbines.

As demonstrated above, BACT limits for Indeck's proposed CTGs are comparable to recently permitted BACT limits at similar facilities; however, it is important to note that surface level comparison does not account for factors such as operational hours and load, elevation, and ambient conditions, which directly impact turbine efficiency. While EPA considered these BACT limits from previously permitted actions, EPA also examined the available literature (such as the Gas Turbine World handbook) and confirmed that the CTGs proposed by Indeck are, in general, considered highly efficient, modern CTG models.

Variations in elevation and ambient temperature will affect a combustion turbine's operation performance and is an important consideration in the comparison of various combustion turbines in different locations. In a discussion about CTG efficiency, it is important to note that the calculated gross CTG power and efficiency are as "measured" across the electric generator terminals at ISO (International Organization for Standardization) site conditions without allowances for inlet filter and duct losses, exhaust stack and silencer losses, gearbox efficiency, or any auxiliary mechanical and electrical systems' parasitic power consumption. ISO design ratings are typically set at 59°F and sea level. To assess site-specific CTG performance, correction factors should be applied. Figures 1 and 2 show the anticipated site-specific efficiency versus load percent at the various ambient conditions in Wharton County, Texas for both the GE 7FA.05 and the Siemens SGT6-5000F(5) turbines. Firgues 1 and 2 include an efficiency curve to estimate the anticipated actual operational scenario for a simple cycle CTG located in Wharton County, Texas. The efficiency has been corrected to represent the output at the site-specific elevation of 69 ft and the various ambient temperatures.

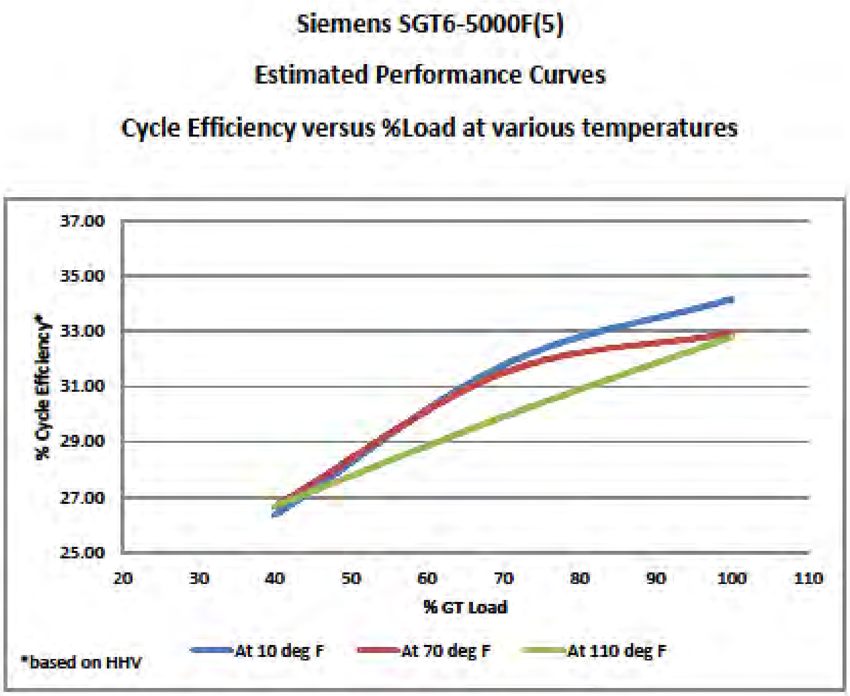
Figure 1. Estimated Performance Curve for GE7FA.05 CTG



From GE datasheets

Temperature	X axis Load	Y Axis Efficiency
10	100	35.14
10	70	31.91
10	40	24.35
70	100	34.44
70	70	31.85
70	40	24.35
110	100	34.09
110	70	30.15
110	40	22.70

Figure 2. Estimated Performance Curve for Siemens SGT6-5000F(5)



From Siemens datasheets

Temperature	X axis	Y Axis
	Load	Efficiency
10	100	34.16
10	70	31.76
10	40	26.33
70	100	32.93
70	70	31.49
70	40	26.66
110	100	32.79
110	70	29.91
110	40	26.68

A 2.5% margin is included in the BACT limits for operation that may occur at varying loads and temperatures other than at 70 degrees and 100% load. For example, at 110 degrees and 70% load, the GE turbine heat rate is 14% higher than at 70 degrees and 100% load. These type of operating conditions (110 deg F and 70% load) will not occur all the time, but some allowance for varying ambient conditions and electric demand is reasonable. We have also allowed a 1.5% allowance for inclusion of startup and shutdown emissions. This is based on the annual startup/shutdown emissions that are accounted for in the total potential emissions. Therefore, the total allowance of 8.5% includes 2.5% (output degradation over time), 2% (compliance margin), 2.5% (varying ambient and electrical demand), and 1.5% (startup/shutdown). This is similar to other margins that EPA has permitted, including Pioneer Valley Region 1,[8] in which EPA found an 8.5% overall compliance margin between short-term full load and longer-term performance reasonable. EPA believes that the use of 8.5% is also reasonable for the Indeck project.

BACT During Startup and Shutdown

BACT applies during all periods of turbine operation, including startup and shutdown. For this project, EPA is proposing a BACT emission limit of 1,276 lb CO_2/MWhr gross output for the GE 7FA.05 combustion turbine or 1,337 lb CO_2/MWhr gross output for the Siemens SGT6-5000F(5) on a 2,500 operational hour rolling basis. The number of startups and shutdowns is limited to 300 per year per turbine on a 12-month rolling basis. All startups and shutdowns are limited to 30 minutes in duration per event. A startup of each turbine is defined as the period that begins when there is measureable fuel flow to the turbine and ends when the turbine load reaches 40 percent. A shutdown of each turbine is defined as the time period that begins when the combustion turbine drops out of the normal operating low-NOx combustion mode (which equates to approximately 40% combustion turbine load) following an instruction to shut down and ends when flame is no longer detected in the combustion turbine combustors. A shutdown event will also end if the combustion turbine is instructed to return to normal low-NOx combustion operating mode and subsequently achieves normal operating low-NOx combustion mode. In addition to the BACT emission limit of 1,276 lb CO_2/MWhr gross output for the GE7FA.05 combustion turbine or 1,337 lb CO_2/MWhr gross output for the Siemens SGT6-5000F(5), we are including a BACT requirement for startup/shutdown that includes the work practice standard to utilize good pollution control practices, safe operating practices and protection of the facility.

BACT Compliance:

Proposed BACT for this project is the use of new natural gas fired, thermally efficient simple cycle combustion turbines combined with evaporative cooling and good combustion and maintenance practices to maintain optimum efficiency for each combustion turbine, with an output based limit of 1,276 lb CO_2/MWhr (gross) for the GE 7FA.05 combustion turbine or 1,337 lb CO_2/MWhr (gross) for

[8] http://www.epa.gov/region1/communities/pdf/PioneerValley/FactSheet.pdf

the Siemens SGT6-5000F(5). Compliance will be based on a 2,500 operational hour rolling basis, calculated daily for each turbine. Indeck will maintain records of tune-ups, combustor maintenance, O_2 analyzer calibrations, and maintenance for each CTG. In addition, records of fuel temperature, ambient temperature, and stack exhaust temperature will be maintained for each CTG. For each CTG, the parameters that will be measured are natural-gas flow rate using an operational non-resettable elapsed flow meter, total amount of fuel combusted on an hourly basis, fuel gross calorific value (GCV) on a high heat value (HHV), carbon content, combustion temperature, exhaust temperature, and gross hourly energy output (MWhr).

Indeck will demonstrate compliance with the CO_2 limit for each CTG by using non-resettable elapsed time fuel flow meters to monitor the quantity of fuel combusted in the electric generating unit and performing periodic scheduled fuel sampling pursuant to 40 CFR § 75.10(a)(3)(ii) and the procedures listed in 40 CFR Part 75, Appendix G. Results of the fuel sampling will be used to calculate a site-specific Fc factor, and that factor will be used in the equation below to calculate CO_2 mass emissions. The proposed permit also includes an alternative compliance demonstration method in which Indeck may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions. The measured hourly CO_2 emissions from each combustion turbine are divided by the measured gross energy output of the combustion turbine (MWhr). The quotient of the hourly measurement (lb CO_2/MWhr, gross) is added to the 2,500 operational hour rolling average and the calculations shall be completed on a daily basis to determine compliance with the BACT limit.

Indeck proposes to determine a site-specific Fc factor using the analysis and GCV in equation F-7b of 40 CFR Part 75, Appendix F. The site-specific Fc factor will be re-determined annually in accordance with 40 CFR Part 75, Appendix F, §3.3.6.

The equation for estimating CO_2 emissions as specified in 40 CFR Part 75, Appendix G, Procedure 2.3 is as follows:

$$W_{CO_2} = (Fc \times H \times Uf \times MW_{CO_2})/2000$$

Where:

W_{CO2} = CO_2 emitted from combustion, tons/hour

MW_{CO2} = molecular weight of CO_2, 44.0 lbs/mole

Fc = Carbon-based Fc-Factor, 1040 scf/MMBtu for natural gas or site-specific Fc factor

H = hourly heat input in MMBtu, as calculated using the procedure in 40 CFR Part 75, Appendix F, §5

Uf = 1/385 scf CO_2/lb-mole at 14.7 psia and 68°F

Indeck is subject to all applicable requirements for fuel flow monitoring and quality assurance pursuant to 40 CFR Part 75, Appendix D, which include:

- The fuel flow meter shall meet an accuracy of 2.0% and is required to be tested once each calendar quarter pursuant to 40 CFR Part 75, Appendix D, § 2.1.5 and § 2.1.6(a).
- Indeck shall determine the Gross Calorific Value (GCV) of pipeline natural gas at least once per calendar month pursuant to 40 CFR Part 75, Appendix D, § 2.3.4.1

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the most (greater than 99%) to the overall emissions from the turbines and additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 2,500 operational hour average, calculated daily. The demonstration of compliance with the BACT emission limit includes emissions during periods of startup and shutdown. The Permittee shall also demonstrate compliance with the startup and shutdown work practice standard by maintaining a copy of the vendor recommendations and maintaining documentation on-site to show that each startup and shutdown event does not exceed the 30 minute duration and that the number of events on a 12-month rolling basis does not exceed 300.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emissions are less than 0.01% of the total CO_2e emissions from the CTGs and are considered a *de minimis* level in comparison to the CO_2 emissions.

IX. Fire Water Pump BACT Analysis (EPN: FP)

Indeck will be equipped with one nominally rated 175-hp diesel-fired pump engine to provide water in the event of a fire. The fire water pump will operate a maximum of 52 hours of non-emergency operation on a 12-month rolling basis for testing and maintenance. The fire water pump engine emissions represent 0.003% of the total facility-wide GHG emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- Selection of Fuel Efficient Engine;
- Fuel Selection; and
- Good Combustion Practices, Operating, and Maintenance Practices.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except fuel selection.

The only technically feasible fuel for the fire water pump engine is diesel fuel. While natural gas-fueled engines may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the fire water pump engine since it will be used in the event of facility-wide power outage, when natural gas supplies may be interrupted.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The selection of fuel efficient engines and good combustion, operating, and maintenance practices are potentially equally effective, but their case-by-case effectiveness cannot be quantified to allow ranking.

Step 4 – Evaluation of Control Technologies, with Consideration of Economic, Energy, and Environmental Impacts

Efficient Engine Design: Indeck will install a new fire water pump engine. It is anticipated that this equipment will be designed for optimal combustion efficiency. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Good Combustion, Operating, and Maintenance Practices: Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the fire water pump engine at least annually or per the manufacturer's specifications. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Step 5 – Selection of BACT

Indeck proposes to use both remaining identified control options to minimize GHG emissions from the fire water pump engine. The following specific BACT practices are proposed for the fire water pump:

- *Selection of Fuel Efficient Engine* - Indeck will purchase fire water pump internal combustion engine (ICE) certified by the manufacturer to meet applicable emission standards at the time of installation and the applicable requirements of 40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines."
- *Good Combustion, Operating, and Maintenance Practices* - Indeck will implement good combustion, operating, and maintenance practices for the fire water pump engine.

BACT for the fire water pump engine will be to limit operation to no more than 52 hours of non-emergency operation per year for the purpose of maintenance, testing, and inspection. Indeck will also monitor hours of operation for the purpose of maintenance, testing, and inspection for each engine on a monthly basis. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

X. Emergency Diesel Generator BACT Analysis (EPN: EDG)

The proposed project will use a Caterpiller C18 ATAAC Diesel engine (or equivalent) with a standby generating capacity of 600ekW. The engine will operate on low sulfur (0.0015%) diesel fuel. The EDG will be an EPA-certified Tier 2 engine which will operate a maximum of 100 hours of non-emergency operation on a 12-month rolling basis for testing and maintenance. The fire water pump emissions represent 0.002% of the total facility-wide GHG emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- Selection of Fuel Efficient Engine;
- Fuel Selection; and
- Good Combustion Practices, Operating, and Maintenance Practices

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible except fuel selection.

The only technically feasible fuel for the emergency generator engine is diesel fuel. While natural gas-fueled generator engines may provide lower GHG emissions per unit of power output, natural gas is not considered a technically feasible fuel for the emergency generator engine since it will be used in the event of facility-wide power outage, when natural gas supplies may be interrupted.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The selection of fuel efficient engines and good combustion, operating, and maintenance practices are potentially equally effective but their case-by-case effectiveness cannot be quantified to allow ranking.

Step 4 – Evaluation of Control Technologies, with Consideration of Economic, Energy, and Environmental Impacts

Efficient Engine Design: Indeck will install a new emergency generator. It is anticipated that this equipment will be designed for optimal combustion efficiency. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Good Combustion, Operating, and Maintenance Practices: Good combustion and operating practices are a potential control option for maintaining the combustion efficiency of the emergency equipment. Good combustion practices include proper maintenance and tune-up of the emergency generator at least annually or per the manufacturer's specifications. EPA concludes that no economic, energy, or environmental impacts warrant elimination of this control option.

Step 5 – Selection of BACT

Indeck proposes to use both remaining identified control options to minimize GHG emissions from the emergency diesel generator. The following specific BACT practices are proposed for the emergency diesel generator:

- *Selection of Fuel Efficient Engine* - Indeck will purchase a new emergency diesel generator internal combustion engine (ICE) certified by the manufacturer to meet applicable emission standards at the time of installation and the applicable requirements of 40 CFR Part 60, Subpart IIII, "Standards of Performance for Stationary Compression Ignition Internal Combustion Engines."
- *Good Combustion, Operating, and Maintenance Practices* - Indeck will implement good combustion, operating, and maintenance practices for the emergency diesel generator.

BACT for the emergency diesel generator engine will be to limit operation to no more than 100 hours of non-emergency operation per year for the purpose of maintenance, testing, and inspection. Indeck will also monitor hours of operation for the purpose of maintenance, testing, and inspection for each engine on a monthly basis. Compliance will be based on runtime hour meter readings on a 12-month rolling basis.

XI. Natural Gas Pipeline Heater (EPN: GH)

The proposed project will be equipped with one new natural gas-fired heater (GH). The heater will have a capacity of 3 MMBtu/hr (HHV) and will be operated no more than 3,500 hours per year. This heater will serve to preheat the natural gas feed into the combustion turbines to maximize combustion efficiency. The pipeline heater represents 0.06% of the facility-wide GHG emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Periodic Tune-up* – Periodically tune-up the heaters to maintain optimal thermal efficiency.
- *Heater Design* – Good heater design to maximize thermal efficiency.
- *Heater Air/Fuel Control* – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.
- *Waste Heat Recovery* – Use of heat recovery from the heater exhausts to preheat the heater combustion air or process streams in the unit.
- *Use of Low Carbon Fuels* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

Use of low carbon fuels, heater design, heater air/fuel control, and periodic tune-ups are considered technically feasible. Waste heat recovery is not applicable to intermittently operated combustion units, and is therefore rejected for the heaters.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of low carbon fuels (up to 100% for fuels containing no carbon)
- Heater design (up to 10%)
- Periodic tune-up
- Heater air/fuel control

Virtually all GHG emissions from fuel combustion result from the conversion of carbon in the fuel to CO_2. Fuels used in industrial processes and power generation are typically coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emissions factor in lb/MMBtu about 55% of that of subbituminous coal. Process fuel gas is a byproduct of chemical processes that typically contain a higher fraction of longer-chain carbon compounds than natural gas and thus results in more CO_2 emissions. Some processes produce significant quantities of hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen has the potential of reducing CO_2 emissions by 100%. Hydrogen is not readily available at the Indeck site and, therefore, is not a viable fuel for the proposed heater. Natural gas is the lowest carbon fuel available for use in the proposed heater.

Good heater design, periodic tune-ups, and heater air/fuel control have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

Step 4 – Evaluation of Control Technologies, with Consideration of Economic, Energy, and Environmental Impacts

Use of Low Carbon Fuel: Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is readily available at the Indeck site and is currently considered a very cost effective fuel alternative. Natural gas is also a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. Natural gas is the fuel choice for most industrial facilities in addition to being the lowest carbon fuel available at this facility.

Heater Design: New heaters can be designed with efficient burners and state-of-the art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. Due to the very low energy consumption of these small intermittently used heaters, only basic heater efficiency features are practical for consideration in the heater design.

Periodic Heater Tune-ups: Periodic tune-ups of the heaters include:

- Preventative maintenance check of gas flow meters,
- Preventative maintenance check of oxygen control analyzers,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range. Due to the minimal use of these heaters, regularly scheduled tune-ups and inspections are not warranted.

Heater Air/Fuel Controls: Manual controls of the air/fuel ratio enable the heaters to operate under optimal conditions ensuring heater efficiency.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the heaters:

- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed heaters. It is the lowest carbon fuel available for use at the facility.
- Good heater design and operation to maximize thermal efficiency and reduce heat loss to the extent practical for heaters of this size in intermittent service.
- Use of manual air/fuel controls to maximize combustion efficiency.
- Clean and inspect heater burner tips and perform tune-ups as needed and per vendor recommendations.
- Limit the operational use of the heaters to no more than 3,500 hours per year per heater on a 12-month rolling basis (2,500 operational hours and 1,000 hours for startup and shutdown).

Use of these practices corresponds with a BACT limit of 624.86 tpy CO_2e for the heater. Compliance with this limit will be determined by calculating the emissions on a monthly basis and keeping a 12-month rolling total of hours of operation, including during startup and shutdown.

XII. Fugitive Emissions from SF_6 Circuit Breakers BACT Analysis (EPN: SF6)

The circuit breakers associated with the proposed units will be insulated with SF_6. The capacity of the circuit breakers associated with the proposed plant expansion is currently estimated to be three (3) breakers with 24.2 lbs SF_6 each, and eleven (11) HV power circuit breakers with 550 lbs SF_6 each.

- *Circuit Breaker Design Efficiency* - In comparison to older SF_6 circuit breakers, modern circuit breakers are designed as a totally enclosed-pressure system with far lower potential for SF_6

emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF_6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF_6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.

- *Alternative Dielectric Material* – Because SF_6 has a high GWP, one alternative considered in this analysis is to substitute another non-GHG substance for SF_6 as the dielectric material in the breakers. Potential alternatives to SF_6 were addressed in the National Institute of Standards and Technology (NIST) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*.[9] The alternatives considered include mixtures of SF_6 and nitrogen, gases and mixtures and potential gases for which little experimental data are available.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Circuit Breaker Design Efficiency* – Considered technically feasible and is carried forward for Step 3 analysis.

- *Alternative Dielectric Material* - According to the report NIST Technical Note 1425, among the alternatives examined in the report, SF_6 is a superior dielectric gas for nearly all high voltage applications. It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF_6 insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture." The mixture of SF_6 and nitrogen is noted to need further development and may only be applicable in limited installations. This alternative has not been demonstrated in practice for this project's design installation. The second alternative of various gases and mixtures has not been demonstrated in practice, and needs additional systematic study before this alternative could be considered technically feasible. The third alternative of potential gases has not been demonstrated in practice, and there is little experimental data available. Therefore, it is clearly not technically feasible for this project and additional studies are needed before this alternative would be considered feasible. Based on the information contained in this report, "it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore, because the alternative dielectric material options have not been demonstrated in practice for this project's proposed design application and would not be commercially available, this alternative is considered technically infeasible.

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[9] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF_6*. NIST Technical Note 1425, Nov. 1997. Available at http://www.epa.gov/electricpower-sf6/documents/new_report_final.pdf

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of efficient circuit breaker design (including state-of-the-art SF_6 technology with leak detection to limit fugitive emissions) is the highest ranked control technology that is feasible for this application.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Since the only remaining control option is the circuit breaker design efficiency, and since that option is selected as BACT, a Step 4 evaluation of the most effective controls is not necessary.

Step 5 – Selection of BACT

Circuit breaker design efficiency is selected as BACT. Specifically, state-of-the-art, enclosed-pressure SF_6 circuit breakers with leak detection is the BACT control technology option. The circuit breakers will be designed to meet the latest American National Standards Institute (ANSI) C37.06 and C37.010 standards for high voltage circuit breakers.[10] The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF6 emissions problems to light before a substantial portion of the SF_6 escapes. The lockout prevents any operation of the breaker due to the lack of "quenching and cooling" SF_6 gas.

BACT compliance will be demonstrated by Indeck through annual monitoring of emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmissions and Distribution Equipment Use.[11] Annual SF_6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

XIII. Fugitive Emissions from Piping Components BACT Analysis (EPN: FUG)

Fugitive emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and CO_2. Because a majority of the GHG fugitive emissions come from methane and the GWP is higher for methane than CO2, a conservative estimate was done to assume that all piping components are in a rich methane stream.

Step 1 – Identification of Potential Control Technologies

- *Leakless/Sealless Technology*
- *Instrument Leak Detection and Repair (LDAR) Programs*
- *Remote Sensing*
- *Auditory/Visual/ Olfactory (AVO) Monitoring*
- *Use of High Quality Components and Materials*

[10] ANSI Standard C37.06, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current Basis* and ANSI Standard C37.010, *Application Guide for AC High-Voltage Circuit Breakers Rated on a Symmetrical Current Basis*.
[11] See 40 CFR Part 98, Subpart DD.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless technologies are effective in eliminating fugitive emissions from valve stems and flanges, though there are still some areas where fugitive emissions can occur (e.g., relief valves).

Instrument monitoring (LDAR) is effective for identifying leaking components and is an accepted practice by EPA. Quarterly monitoring with an instrument and a leak definition of 500 ppm is assigned as a control effectiveness of 97%. The Texas Commission on Environmental Quality's LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

Remote sensing using infrared imaging has proven effective in identifying leaks, especially for components in difficult to monitor areas. LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[12]

AVO monitoring is effective due to the frequency of observation opportunities, but it is not very effective for low leak rates. It is not preferred for identifying large leaks of odorless gases such as methane. However, since pipeline natural gas is odorized with very small quantities of mercaptan, AVO observation is a very effective method for identifying and correcting leaks in natural gas systems. Due to the pressure and other physical properties of plant fuel gas, AVO observations of potential fugitive leaks are likewise moderately effective.

The use of high quality components is also effective relative to the use of lower quality components.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Although the use of leakless components, instrument LDAR and/or remote sensing of piping fugitive emission in natural gas service may be somewhat more effective than as-observed AVO methods, the incremental GHG emissions controlled by implementation of the TCEQ 28 LAER LDAR program or a comparable remote sensing program is considered a *de minimis* level in comparison to the total project's proposed CO_2e emissions. Accordingly, given the costs of implementing 28 LAER or a comparable remote sensing program when not otherwise required, these methods are not economically practicable for GHG control from components in natural gas service. Given that GHG fugitives are conservatively estimated to be little more than 2 tons per year CH_4, there is, in any case, a negligible difference in emissions between the considered control alternatives.

[12] 73 FR 78199-78219, December 22, 2008.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for natural gas components, EPA proposes to incorporate as-observed AVO as BACT for the natural gas piping components. The proposed permit contains a condition to implement AVO inspections on a daily basis.

XIV. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, Indeck Warton ("Indeck"), LLC, and its consultant, Tetra Tech, Inc., ("Tetra Tech"), and adopted by EPA.

A draft BA has identified six (6) species listed as federally endangered or threatened in Wharton County, Texas:

Federally Listed Species for Wharton County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	Scientific Name
Birds	
Whooping crane	*Grus americana*
Attwater's prairie chicken	*Tympanuchus cupido attwareri*
Interior least tern	*Sterna antillarum anthalassos*
Mammals	
Louisiana black bear	*Urus americanus luteolus*
Red wolf	*Canis rufus*
Fishes	
Sharpnose shiner	*Notropis oxyfhynchus*

EPA has determined that issuance of the proposed permit will have no effect on any of the six listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area. Because of EPA's "no effect" determination, no further consultation with the USFWS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XV. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Tetra Tech, Inc. ("Tetra Tech") and submitted in March 5, 2014.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be (1) the site facility containing the construction footprint of the two new natural gas combustion turbines for the Indeck Wharton Energy Center and (2) a 3,900-foot natural gas transmission pipeline with a 100-foot right-of-way. The site facility and pipeline corridor cover approximately 164 acres of land. Tetra Tech conducted a desktop review within a 1.0-mile radius area of potential effect (APE) and a field survey within 0.5-mile radius of the APE. The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the desktop review, four historical and two archaeological sites were identified, but none of them were eligible for listing on the National Register (NR). Based on the field survey, that included shovel testing, eight historical and two archaeological sites were identified and all but one were recommended to be ineligible for listing on the NR. The remaining historical site was recommended to be potentially eligible for listing on the NR; however, it is outside the APE and will not be visually impacted by the proposed project.

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to Indeck will not affect properties potentially eligible for listing on the National Register.

On February 24, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XVII. Conclusion and Proposed Action

Based on the information supplied by Indeck, our review of the analyses contained in the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Indeck a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

Appendix

Table 1A. Annual Emission Limit – Option 1: GE 7FA.05 CT

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2,6]	BACT Requirements
				TPY[1]		
01 02 03	GT1 GT2 GT3	Natural Gas Fired-Simple Cycle Turbine, each	CO_2	320,703[3]	321,028[3]	- BACT limit of 1,276 lb CO_2/MW-hr (gross) on a 2,500 operational hour rolling basis, rolling daily, each turbine. -Not to exceed 2,500 hours of operation on a 12-month rolling basis per turbine, excluding startup and shutdown. -See permit condition III.A.2 and 4.
			CH_4	5.93[3]		
			N_2O	0.59[3]		
04	EDG	Emergency Diesel Generator	CO_2	48.51	48.68	- Not to exceed 100 hours of non-emergency operation on a 12-month rolling basis. - See permit condition III.C.
			CH_4	0.002		
			N_2O	0.0004		
05	FP	Firewater Pump Engine	CO_2	5.32	5.34	- Not to exceed 52 hours of non-emergency operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit condition III.B.
			CH_4	.0004		
			N_2O	0.00003		
06	GH	Natural Gas Pipeline Heater	CO_2	624.23	624.78	- Not to exceed 3500 hours of operation on a 12-month rolling basis - Use of Good Combustion Practices. See permit condition III.D.
			CH_4	0.01		
			N_2O	0.001		
07	SF6	Fugitive SF_6 Circuit	SF_6	No Numerical	No Numerical	Work Practices. See

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2,6]	BACT Requirements
				TPY[1]		
		Breaker Emissions		Limit Established[5]	Limit Established[5]	permit condition III.E.
08	FUG	Components Fugitive Leak Emissions	CH_4	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of AVO Program. See permit condition III.F.
Totals[4]			CO_2	962,787	**965,959**	
			CH_4	92.11		
			N_2O	1.77		
			SF6	0.015		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities. All emissions are expressed in terms of short tons.
2. Global Warming Potentials (GWP): $CO_2 = 1$, $CH_4 = 25$, $N_2O = 298$, $SF_6=22{,}800$
3. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the natural gas fired simple cycle turbines applies to each turbine and is not a combined limit.
4. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.
6. Fugitive Leak Emissions from SF6 and FUG are estimated to be 0.0153 TPY SF_6 (348.99 TPY CO_2e) from SF61 and 0.02 TPY CO_2 and 74.3 TPY CH_4 (74.31 TPY CO_2e) from FUG. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
7. Annual CO_2e emissions inTPY are based on 12-month rolling total basis.

Table 1B. Annual Emission Limit – Option 2: Siemens SGT-5000F(5)

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2,7]	BACT Requirements
				TPY[1]		
01 02 03	GT1 GT2 GT3	Natural Gas Fired-Simple Cycle Turbine, each	CO_2	358,165[3]	358,529[3]	- BACT limit of 1,337 lb CO_2/MWhr (gross) on a 2,500 operational hour rolling basis, rolling daily, each turbine. -Not to exceed 2,500 hours of operation on a 12-month rolling total basis per turbine. -See permit condition III.A.2 and 4.
			CH_4	6.63[3]		
			N_2O	0.66[3]		
04	EDG	Emergency Diesel Generator	CO_2	48.51	48.68	- Not to exceed 100 hours of non-emergency operation on a 12-month rolling total basis - See permit condition III.C.
			CH_4	0.002		
			N_2O	0.0004		
05	FP	Firewater Pump Engine	CO_2	5.32	5.34	- Not to exceed 52 hours of non-emergency operation on a 12-month rolling total basis - Use of Good Combustion Practices. See permit condition III.B.
			CH_4	0.0002		
			N_2O	0.00004		
06	GH	Natural Gas Pipeline Heater	CO_2	624.23	624.78	- Not to exceed 3500 hours of operation on a 12-month rolling total basis - Use of Good Combustion Practices. See permit condition III.D.
			CH_4	0.01		
			N_2O	0.001		
07	SF6	Fugitive SF_6 Circuit Breaker	SF_6	No Numerical Limit	No Numerical Limit	Work Practices. See permit condition III.E.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2,7]	BACT Requirements
				TPY[1]		
		Emissions		Established[6]	Established[6]	
08	FUG	Components Fugitive Leak Emissions	CH_4	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of AVO Program. See permit condition III.F.
Totals[5]			CO_2	1,075,173	**1,078,460**	
			CH_4	94.2		
			N_2O	1.98		
			SF6	0.015		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities. All emissions are expressed in terms of short tons.
2. Global Warming Potentials (GWP): $CO_2 = 1$, $CH_4 = 25$, $N_2O = 298$, SF_6=22,800
3. The GHG Mass Basis TPY limit and the CO2e TPY limit for the natural gas fired simple cycle turbines applies to each turbine and is not a combined limit.
4. All values indicated as “No Numerical Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.
6. Fugitive Leak Emissions from SF6 and FUG are estimated to be 0.0153 TPY SF_6 (348.99 TPY CO_2e) from SF61 and 0.02 TPY CO_2 and 74.3 TPY CH_4 (74.31 TPY CO_2e) from FUG. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
7. Annual CO_2e emissions inTPY are based on 12-month rolling total basis.